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WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

PacifiCorp

Docket Number: PA-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

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I. FILING DATA

Utility	Parties to the Filing
PacifiCorp 825 NE Multnomah, Suite 2000 Portland, Oregon 97232	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
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II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	As Amended
Production Cost	$863,127,579	$866,277,276
Transmission Cost	$187,309,496	$185,057.676
(Less) New Large Single Load Costs		
Total Contract System Cost	1,050,437,075	$1,051,334,952
Total Retail Load (MWh)	21,409,663	21,509,637
(Less) New Large Single Load	0	
Total Retail Load (Net NLSL)	21, 409,663	21,509,637
Plus Distribution Losses	1,070,482	1,318,834
Total Contract System Load (MWh)	22,480,119	22,728,471
FY 2006 Base Period ASC ($/MWh)	$46.73	$46.26

B. FY 2009 (Exchange Period) ASC without New Resource Additions ($/MWh)

	FY 2009
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$49.36**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions - See Table1 in Section III.B for details

Resource	Lake Side Capital Building	Group 1	CCCT Plant West	Group 3	Group 4
Delta*	1.88	1.47	1.22	1.15	0.65

* Base ASC is $49.36/MWh. The Delta is the differential between the additions of each of the five resource groups starting with the Base ASC.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

For more information regarding the proposed 2008 ASCM, refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. <u>ASC Determination Process Guidelines and Expedited Review Process</u>

The purpose of BPA's expedited review process was to estimate exchanging Utilities' ASCs for FY 2009 that could be noticed by the Administrator and incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding relied on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an excel based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008 thru September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For COUs, the rate of return is equal to the COU's weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items.

Contract System Costs:
The Contract System Cost is defined as the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Loads:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any new large single load (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Off-System Sales

The purchased power (excluding REP reversal expenses) is an account of Schedule 3, Expenses, and includes all purchases the Utility made during the year, including power exchanges. Listed in the information is the statistical classification code for all transactions. Refer to the FERC Form 1, page 326, for definitions of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data is used based on the cost of service study used as the basis for retail rates at the time of review.

D. ASC Forecast

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Costs and codes filed on May 7, 2008 by PacifiCorp, and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base

1. 302 Franchise & Consent

Direct Analysis requires justification of the cost allocations to Production or Transmission

a Statement of Issue: In the May 7th filing, PacifiCorp directly assigned this account to Production.

b Statement of Facts: The proposed ASCM permits direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate. BPA will not allow

Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if Utility through direct analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

c PacifiCorp's Response to the Issue: The Revised Protocol Methodology allows only the following two methods of allocation to be used for this account (Page 13 of Appendix B).

302 Franchise & Consent

Distribution	S
Production, Transmission	SG

A detailed description of the assets in this account has previously been provided in response to BPA Data Request 4. See Tab – Electric Plant in Service. Except for $1 million of rate base assigned directly to Idaho, costs in these accounts are allocated on the SG factor and have been allocated to production since they are the costs associated with acquiring new hydro electric licenses. (The Company has updated the filing to reflect the $1 million assigned incorrectly to production rather than distribution). Of the total of $118 million in this account, $80 million is related to the relicensing of the North Umpqua project, $14 million to the Grace Hydroelectric plant, $4 million to the Condit Hydroelectric plant and the remaining to smaller hydroelectric projects.

d. Analysis of Position and Decision: PacifiCorp provided sufficient information to support the direct analysis of this account.

2. Account 303, Intangible Plant Miscellaneous

a. Statement of Issue: In the May 7th filing, PacifiCorp directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: The proposed ASCM permits direct analysis only for specified accounts. The ASCM contains default functionalization methods in the absence of direct analysis where appropriate. BPA will not allow Utilities to use a combination of direct analysis and a prescribed functionalization method for the same account. Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if Utility through direct analysis, can justify how the ratio adequately reflects the functional nature of the costs included in any account or cost item being functionalized by the ratio.

c. PacifiCorp's Response to the Issue: Account 303 – Intangible Plant. The Revised Protocol Methodology allows the following methods of allocation to be used for this account (Page 13 of Appendix B).

303 Miscellaneous Intangible Plant

Distribution	S
Remaining Steam Plants	SG
Peaking Plants	SSGCT
Cholla	SSGCH
Pacific Hydro	SG
East Hydro	SG
Transmission	SG
Customer Related	CN
General	SO

A detailed description of the assets in this account is included in the tab "Account 303" included as part of the ASC filing.

This account lists 118 assets totaling $548 million. Of these assets, $86 million are allocated on the SG or SE factor and have been assigned to production or transmission as appropriate as follows.

Production

Deer Creek Intangible Assets
Craig Plant Maintenance Management System
Caiso Energy Management Analysis
Rogue River Hydroelectric Intangibles
Improvements to Plant Owned By James River
Gadsby Intangible Assets
Eagle Point Hydro Assets
Swift 2 Improvements
Bear River-Settlement Agreement
Apogee - Energy Exchange Program
Link River Dam Rights
Hayden – Vibration Software
Steam Plant Intangible Assets
Commercial & Trading Hedge Accounting Standards

Transmission

Transmission Intangible Assets
Transmission Wholesale Billing System
Idaho Transmission Customer Owned

The remaining $462 million consists of various computer hardware and software assets. Two assets dwarf the remaining assets – the Company's accounting software – SAP ($159 million) and Customer Service System ($102 million) which support all areas of the Company and have been allocated on the PTD factor.

Of the remaining $201 million in assets, the following assets have been allocated to Distribution

Distribution Automation Pilot Project
Miscellaneous Projects – Idaho, Oregon, Washington, Wyoming & Utah

The following assets have been allocated to **Production**

Fuel Management System
Energy Management System
Heat Rate Performance Software
Retail Energy Services Tracking
Energy Commodity System Software
2002 GRID Net Power Costs Modeling
Mid Office Improvement Project
SB1149 - Accommodate CSS and MDM to SB1149
C&T Official Record Information System
APOGEE – Energy Exchange System
K2 - KWI Commercial Risk System
Electronic Tagging System - Merchant

The following assets are allocated **TD**

Automate Pole Card System
Salt Lake SCADA System
Pole Attachment Management System
Ranger EMS/SCADA System

Of the remaining assets, none can be clearly assigned to production, transmission, distribution or TD as they support all of these areas and the Company has allocated then on the PTD factor.

d. Analysis of Position and Decision: PacifiCorp provided information to support the direct analysis of this account.

3. **Account 302 & 303 – Accumulated Amortization of Intangible Plant**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the amortization of 302 Franchise & Consent to Production. In addition, account 303 was functionalized using Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production. What is the regulatory treatment of this account?

c. PacifiCorp's Response to the Issue: The accumulated amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 302 & 303 – Accumulated Amortization of Intangible Plant

4. **Account 399– Other Tangible Property**

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 399 "Other Tangible Property" to Production without adequate support for the Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production, Transmission or Distribution. Direct Analysis requires justification of the cost allocations to Production

c. PacifiCorp's Response to the Issue: This account includes only "Plant used in Mining Activities" and the Company includes it in rate base in regulatory proceedings and earns a return on the asset. A detailed description of the items in the account is found on page 450.1 supporting page 206 – 207, line 97. The Company also owns part of the Jim Bridger and Trapper mines. All costs associated with these mines, except for a return on the rate base, are included as fuel costs. PacifiCorp adds this investment on this line. (Backup – 2006 Results of Operations pages 8.2 & 8.3)

d. Analysis of Position and Decision: PacifiCorp provided sufficient information to support the direct analysis of this account.

5 Account 114 Acquisition Adjustments

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 114 Acquisition Adjustments to Production without adequate support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 114 Acquisition Adjustments requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution.

c. PacifiCorp's Response to the Issue: A description of the assets in this account has previously been provided in response to BPA Data Request 4. See Tab – Miscellaneous Rate Base. The costs included in this account (all allocated on the SG allocation factor) are related to the Company's purchase of the Craig, Hayden, Cholla and Wyodak plants. They are allocated to the production function and the Company includes the asset in rate base in regulatory proceedings and earns a return on the asset.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 114 Acquisition Adjustments to Production.

6 Account 115 – Amortization of Acquisition Adjustment

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the Accumulated Amortization to Production without adequate support for the Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production. What is the regulatory treatment of this account? Why is the total less than the production allocation? $34,493,002 vs. $36,062,817. The accumulated amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

c. PacifiCorp's Response to the Issue: The amortization of the rate base in this account follows the treatment accorded the rate base described above. The total is less than the production allocation because of an error in the calculation of the Idaho amortization. The Company has corrected this error in this filing of its ASC.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 115 Accumulated Amortization of Acquisition Adjustments to Production.

7 Account 182.3 – Other Regulatory Assets

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 182.3 Other Regulatory Assets using Direct without adequate support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 182.3 Other Regulatory Assets requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that these assets can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Regulatory Assets includes only those assets included in rate base in a regulatory proceeding. They total $81 million compared to $1.396 billion shown on the FERC Form One.

The following assets have been allocated to **Production**

182.300	Conservation
182.302	Direct Access – California
182.304	Direct Access - Oregon
182.392	Conservation
182.393	Conservation
182.394	Conservation
182.396	Conservation
182.3993	Cholla Transaction Costs
182.3994	Cholla Transaction Costs
182.3995	Cholla Transaction Costs
182.3999	DSM Regulatory Assets – Accruals

The following assets have been allocated **PTD**

182.391	Environmental Remediation
182.387	FAS 87/88 Utah

The following assets with 182.3990 have been allocated **Production**

187003	Retail Access Project – Oregon
187004	Energy Trust
187050	Cholla Transaction Costs
187051	Washington Colstrip #3 Regulatory Asset
187058	Trail Mountain Mine Closure Costs
187070	Trail Mountain Mine Costs - Deseret Settlement

187107 Glenrock Mine Excluding Reclamation - UT
187111 Noell Kempf Cap - UT
187112 P&M Strike Amort - UT
187903 Wyoming - Deferred Excess Net Power Costs
187904 Idaho - Deferred Net Power Costs
187906 Def Excess NPC - Oregon Ue116 Bridge
187907 Or Ue134 Power Cost

The following assets with 182.3990 have been allocated **Transmission**

187081 RTO Grid West N/R - OR
187082 RTO Grid West N/R - WY

The remaining assets with 182.3990 have been allocated PTD as they support all functional areas. The largest two are assets are 1998 – Early Retirement (Oregon) and May 2000 Transition Costs (Oregon). These comprise over 80% of Account 182.399 not directly assigned to Production, Transmission and Distribution.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 182.3 Regulatory Assets.

8 Account 186 – Miscellaneous Deferred Debits

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 186 – Miscellaneous Deferred Debits to production using Direct Analysis without providing sufficient support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those assets can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Deferred Debits includes only those assets included in rate base in a regulatory proceeding. They total $42 million compared to $58 million shown on the FERC Form One. The Company believes all the Miscellaneous Deferred Debits are production related.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of A Account 186 – Miscellaneous Deferred Debits

9 Account 253 – Miscellaneous Deferred Credits

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 253 Miscellaneous Deferred Credits using Direct Analysis without providing sufficient support for the Direct Analysis.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those liabilities can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Miscellaneous Rate Base includes only those liabilities included in rate base in a regulatory proceeding. They total $16 million compared to $62 million shown on the FERC Form 1. Within this account, liabilities allocated SE or SG and Oregon DSM loans are production related. Unearned Joint Pole Use revenue allocated directly to a state is distribution related. The remaining liability, a software liability is assigned PTD.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 253 - Miscellaneous Deferred Credits.

10 Account 253 – Miscellaneous Deferred Credits

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 254 Other Regulatory Liabilities using Direct Analysis, without sufficient justification for the cost assignments.

b. Statement of Facts: The functionalization of Account 186 – Miscellaneous Deferred Debits requires a Direct Analysis, which requires justification of the cost allocations to Production, Transmission and Distribution. What is the regulatory treatment of this account and components?

c. PacifiCorp's Response to the Issue: The Company begins with the assumption that those liabilities can only be included in the ASC calculation if the State Regulatory Agencies have approved them for recovery in a rate making proceeding. The TAB – Miscellaneous Rate Base includes only those liabilities included in rate base in a regulatory proceeding. They total $4 million compared to $109 million shown on the FERC Form One. Within this account, the Property Insurance reserve is assigned PTD. The Trojan Nuclear Plant liability is assigned to Distribution.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information for the Direct Analysis of this account. The Functionalization of separate sub accounts will be addressed in the October 1, 2008 filing.

11 Account 244 - Long-Term Portion of Derivative Instrument Liabilities

a. Statement of Issue: Long-Term Portion of Derivative Instrument Liabilities appears in two places on the June 6, 2008 filing template.

b. Statement of Facts: Long-Term Portion of Derivative Instrument Liabilities should only appear in the Current and Accrued Liabilities Section.

c. Analysis of Position and Decision: Given Long-Term Portion of Derivative Instrument Liabilities functionalization to distribution, the adjustment for the double counting will have no impact on the ASC.

12 Functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio

a. Statement of Issue: Correct functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio

b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c. Analysis of Position and Decision: The functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from distribution to PTD in the ASC Template

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3:

1. **Functionalization of Customer Service and Informational**

   a. Statement of Issue: Correct functionalization of Customer Service and Informational in the Labor Ratio

   b. Statement of Facts: Customer Service and Informational in the Labor Ratio should have been functionalized to Distribution rather than Direct ASC Template.

   c. PacifiCorp's Response to the Issue: Four types of costs are contained in this account: Expense associated with current conservation programs (DSM DIRECT); the amortization of previously capitalized conservations programs (DSM AMORT); Customer Service (CUST SERV); and Customer Assistance (CUST ASSIST EXP and CUST ASST EXP – GENL). The first two cost categories are production costs. The last two cost categories have been assigned to the distribution function. A detailed description of the expense in this account is included in the tab "Account 908" included as part of the ASC filing. The Company recovers these expenses by including them in its revenue requirement in regulatory proceedings.

   d. Analysis of Position and Decision: PacifiCorp identified DSM related costs within Account 908, with the correct functionalization to Production. The remainder of this account was functionalized to Distribution

2. **Oregon Public Purpose Charge**

   a. Statement of Issue: In its May 7th filing, PacifiCorp the Oregon Public Purpose Charge using Direct Analysis, without sufficient justification for the cost assignments.

   b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production, Transmission or Distribution

   c. PacifiCorp's Response to the Issue: ORS 757.612 specifies that the public purpose charge be used for cost-effective conservation and market transformation, the above-market costs of renewable energy resources, low-income weatherization. In addition school districts may use the funds allocated to them to fund energy audits, weatherization, energy efficiency, energy conservation education programs, purchasing energy from environmentally focused sources and investing in renewable energy sources. All these are production related and the Company has assigned that portion of the public purpose charge to production. The final portion of the Public Purpose Charge is transferred to Housing and Community Services and has been assigned to distribution. The detailed accounting for 2006 has previously been provided in response to BPA Data Request 6.

d. Analysis of Position and Decision: The functionalization of the Oregon Public Purpose Charge will be addressed in the October 1, 2008 Filing.

3. Account 404 – Amortization of Intangible Assets (302 & 303)

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized the amortization of 302 Franchise & Consent to Production. In addition, account 303 was functionalized using Direct Analysis.

b. Statement of Facts: Direct Analysis requires justification of the cost allocations to Production. What is the regulatory treatment of this account?

c. PacifiCorp's Response to the Issue: The amortization of the rate base in these accounts follows the treatment accorded the rate base described above.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the functionalization of Account 302 & 303 – Amortization of Intangible Plant

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

1. Account 421 - Miscellaneous Non-operating Income

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 421 – Miscellaneous Non-operating Income to Distribution.

b. Statement of Facts: Account 421– Miscellaneous Non-operating Income to Distribution requires a Direct Analysis with a default functionalization to Production. PacifiCorp directly functionalized this account to Distribution without the required analysis.

c. PacifiCorp's Response to the Issue: Two cost categories are included in this account. The vast majority ($475 million) of the total amount, $480 million is related to FAS 133 Unrealized Gains. Consistent with the treatment of unrealized gains recorded on the balance sheet which have been assigned to distribution, the income associated with them has also been assigned to distribution. The second category is miscellaneous non-operating income which has also been assigned to distribution as it is unrelated to the utility operations of the Company. A detailed description of the expense in this account is included in the tab "Account 421" included as part of the ASC filing.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 421 – Miscellaneous Non-Operating Income.

2. Account 456 – Other Electric Revenue

a. Statement of Issue: In its May 7th filing, PacifiCorp functionalized Account 456 – Miscellaneous Non-operating Income using Direct Analysis, without adequate support for the functionalization.

b. Statement of Facts: Account 456 – Miscellaneous Non-operating Income is to be functionalized using Direct Analysis with a default functionalization to Production.

c. PacifiCorp's Response to the Issue: Account 456.1, Wheeling Revenue is assigned to Transmission. Accounts 456.20, 456.23, 456.24 & 456.25 are distribution related assigned directly to each state. Accounts 456.22 and 456.4 are related to DSM tariff revenues and the proposed ROD states that they should not be included as an expense in ASC filings – the Company as therefore assigned them to distribution. Account 456.21 – Use of facilities should be assigned TD and Accounts 456.26, 456.266, 456.65 & 456.66 are wheeling related and are assigned to transmission. This account is included in regulatory proceedings.

d. Analysis of Position and Decision: PacifiCorp has provided sufficient information to support the Direct Analysis of Account 456 – Miscellaneous Non-operating Income.

SCHEDULE 4: Average System Cost

1 **Distribution Loss**:

a. Statement of Issue: In its filing, PacifiCorp used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. PacifiCorp's Response to the Issue: The Company will follow the proposed ROD and either provide a loss study or follow the methodology described by BPA in the ROD.

d. Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor outlined in the ASCM ROD, Section 4.10.5. PacifiCorp's Distribution Loss Factor has been set at 8.16%.

2 Contract System Loads: New Large Single Load (NLSL)

a Statement of Issue: The May 7^{th} Appendix 1 filing did not require and therefore did not include information on NLSL MWh. BPA now requires this data to be included in the determination of a Utility's ASC.

b Statement of Facts: PacifiCorp submitted data identifying one potential NLSL usage of 342,068 MWh. BPA determined this load by the evaluation of PacifiCorp provided data.

c Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculation of a Utility's ASC and, therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

3 Contract System Costs: New Large Single Load (NLSL) Costs

a Statement of Issue: The May 7th filing Appendix 1 template did not require and therefore did not include information on NLSL costs. BPA now requires this data to be included in the determination of a Utility's ASCs.

b Statement of Facts: BPA determined the cost of serving the potential NLSL using the fully allocated cost of all escalated base period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5. In addition, BPA will not allow a Utility's ASC to increase as a result of excluding the costs of resources used to serve NLSLs.

c Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculations of a Utility's ASC and therefore, BPA removed the NLSL and associated costs from the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1 Maintenance of General Plant (GPM) Ratio: Miscellaneous Equipment

a Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

b Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. BPA determined a change in PacifiCorp's ASC using the methods as described in the ASCM ROD, section 4.2.10.

Table 1 below identifies the New Resource Additions information provided from PacifiCorp. Tables 1, ASC New Resource Additions and Table 2, FY 2009-2013 ASC Summary, summarize the results.

Table 1: ASC New Resource Additions

		6/30/2007	8/1/2008	9/14/2008	12/31/2008	6/1/2009
		Lake Side Capital Building	Group 1	CCCT Plant West (525 MW)	Group 3	Group 4
		NG	Other	NG	Other	Other
Other Production Plant						
Other Production	340-346	$138,979,231	$318,455,478	$128,123,754	$247,147,430	$159,760,358
Fuel Stock	151					
Plant Materials and Operating Supplies	154					
EPA Allowances	158.1-158.2					
Other Expense						
Other Power - Fuel	547	$64,661,215		$59,610,616		
Other Power - Operations (Excluding 547 - Fuel)	546-550					
Other Power - Maintenance	551-554	$2,278,366	$4,387,932	$2,100,406	$4,961,381	$3,159,328
Property Insurance	924	$418,246	$958,365	$385,578	$743,770	$480,785
Depreciation	403	$3,660,222	$10,998,583	$3,374,327	$10,003,894	$6,466,690
Firm Sales for Resale ($)	447					
Firm Sales for Resale (MWh)						
Expected Annual Generation (MWh)		1,196,527	$367,629	1,103,068	$392,774	290,960
Property Taxes Production						
Total Production Property	262	$1,206,997	$2,765,700	$1,112,720	$2,146,409	$1,387,476

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following table summarizes the forecast of Contract System Costs and Contract System Loads for purposes of determining PacifiCorp's forecast ASC for FY 2009 through FY 2013. The procedure in making the determinations are outlined in the 2008 ASCM ROD and described in this report. The results shown herein are forecast for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and for use in the calculation of the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**
CONTRACT SYSTEM COST ($)					
Production	1,150,023,901	1,124,484,515	1112137282	1,112,029,163	1113257611
Transmission	179,212,567	177,629,054	176194438	174,796,728	173490803
NLSL Fully Allocated Cost ($/MWh)	57.97	56.50	55.52	55.12	54.73
(Less) NLSL Costs	19,828,379	19,327,715	18991028	18,853,328	18721359
Total Contract System Cost	1,309,408,089	1,282,785,854	1269340692	1,267,972,564	1268027055
CONTRACT SYSTEM LOAD (MWh)					
Total Retail Load @ Meter	22,016,008	22,207,898	22,427,330	22,654,332	22,880,278
(Less) NLSL	342,068	342,068	342,068	342,068	342,068
Total Retail Load (Net or NLSL)	21,673,940	21,865,830	22,085,262	22,312,264	22,538,210
Distribution Loss	1,825,676	1,841,588	1,859,784	1,878,609	1,897,345
Total Contract System Load	23,499,616	23,707,418	23,945,046	24,190,873	24,435,555
AVERAGE SYSTEM COST					
ASC ($/MWh)	**55.72**	**54.11**	**53.01**	**52.42**	**51.89**

VI. BPA CONCLUSION

This ASC determination is BPA's best estimate of PacifiCorp's FY 2009 ASC based on the information and data provided from PacifiCorp during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination, FY 2009. This determination is made solely for purposes of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance to the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of PacifiCorp Utilities (PacifiCorp) for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The amended Appendix 1 Filing, Forecast Model, and NLSL assessment used to calculate PacifiCorp's ASCs can be viewed at BPA ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.